Simulation of CO_2 for Enhanced Oil Recovery

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Abstract

CO_2-EOR is one of the main methods for tertiary oil recovery. The injection of CO_2 does not only improve oil recovery, but also contribute to the mitigation of greenhouse gas emissions. In this study, near well simulations were performed to determine the optimum differential pressure and evaluate the effect of CO_2 injection in oil recovery. By varying the drawdown from 3 bar to 20 bar, the most suitable differential pressure for the simulations was found to be 10 bar. The effect of CO_2 injection on oil recovery was simulated by adjusting the relative permeability curves using Corey and STONE II correlations. By decreasing the residual oil saturation from 0.3 to 0.15 due to CO_2 injection, the oil recovery factor increased from 0.52 to 0.59 and the water production decreased by 22%.

Keywords: CO_2, enhanced oil recovery, relative permeability, near well simulation

1 Introduction

According to Melzer (2012) and Jelmert *et al* (2010), after water flooding CO_2-EOR is the most commonly used method for improved oil recovery. CO_2-EOR can be used for increased oil production in combination with CO_2 storage to mitigate CO_2 emissions. The method is widely used in the United States where the price of CO_2 is relatively low due to large resources of natural CO_2. More than 70 operating fields in USA use CO_2 for enhanced oil recovery. The majority of oil fields use closed-loop systems during CO_2-EOR. The working principle of CO_2-EOR is depicted in Figure 1. CO_2 is injected into the reservoir using injection wells. When CO_2 comes in contact with oil in the reservoir, the oil properties change and the oil becomes more mobile. In addition, the injected CO_2 displaces the oil and forces it to move towards the production well. Significant amount of the injected CO_2 is retained inside the reservoir pores and some amounts are produced together with the oil to the surface. On the surface, CO_2 is separated from the oil and re-injected into the reservoir, and is thereby giving rise to a closed loop system. The CO_2 which is separated from the oil, can also be injected to the underlying aquifer for sequestration (Jelmert *et al*, 2010; Zhang *et al*, 2015).

1.1 Mechanism of CO2-EOR

Crude oil contains hundreds of hydrocarbons and many of them contain more than 30 carbon atoms. CO_2 is miscible in hydrocarbons with less than 13 carbon atoms. CO_2 becomes mutually soluble with the immobile oil as the light hydrocarbons from the oil dissolves in the CO_2 and CO_2 dissolves in the oil. When CO_2 and oil are miscible, the interfacial tension disappears. This means that the physical forces holding the two phases apart are no longer present, which make it possible for the CO_2 to displace the oil that is trapped in the pores of the rock. The efficiency of CO_2-EOR is dependent on the miscibility of CO_2 in oil, and the miscibility is strongly affected by pressure. The solubility of CO_2 in oil depends on the type of oil where higher amount of CO_2 can be solved in light oil than in heavy oil. Mobility of the oil increases mainly due to interfacial tension reduction, oil viscosity reduction, oil swelling and due to acid effect on rock (Ghoodjani and Bolouri, 2011).

Interfacial tension strongly influences relative permeability between CO_2 and oil. Due to dissolution inside the reservoir, interfacial tension is reduced when CO_2 is mixed with oil resulting in increased relative permeability and mobility of the oil. The more mobile the oil is, the easier it is to produce and a higher oil recovery can be achieved (Ghoodjani and Bolouri, 2011).

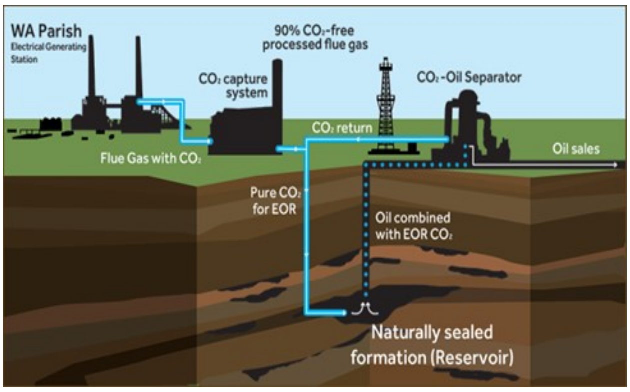

Figure 1. Working principles of CO_2-EOR (Advanced Resources International and Melzer Consulting, 2010).

When CO_2 dissolves in oil, the viscosity of the oil decreases significantly. The reduction of oil viscosity is highly dependent on the initial viscosity of the oil. Less viscous oil will be less affected by the CO_2, while for more viscous oils, the effect of viscosity reduction is more pronounced. The reduction in oil viscosity will cause an increase in the oil relative permeability. This will reduce the residual oil saturation in the reservoir and improve the oil recovery (Ghoodjani and Bolouri, 2011).

CO_2 interacts with the oil in the reservoir and dissolves in the oil at certain reservoir conditions. The dissolution of CO_2 in oil causes the oil to swell. Reservoir characteristics, as pressure and temperature as well as oil composition, determine the strength of the oil swelling effect (Ghoodjani and Bolouri, 2011). Swelling plays an important role in achieving better oil recovery. Variation in the swelling factor influences on the residual oil saturation, which is inversely proportional to the swelling factor. Residual oil saturation, in turn, affects the relative permeability, which plays a crucial role in oil recovery (Ghoodjani and Bolouri, 2011).

Swollen oil droplets force fluids to move out of the pores and oil that initially was unable to move out of the pores under certain pressure conditions will now be forced to move towards the production well. Hence, oil swelling causes drainage effect that decreases the residual oil saturation (Ghoodjani and Bolouri, 2011).

2 Olga and Rocx

OLGA is a one-dimensional transient dynamic multiphase simulator used to simulate flow in pipelines and connected equipment. OLGA consists of several modules depicting transient flow in a multiphase pipeline, pipeline networks and processing equipment. Since Olga is a spatially 1-dimensional simulator, only one set of equations is used for the calculation of the well properties in the length direction. That is, the properties of the fluid are independent of the radius of the well and changes therefore only with length and time (Thu, 2013).

Rocx is a three-dimensional near-well model coupled to the OLGA simulator to perform integrated wellbore-reservoir transient simulations. Rocx can simulate three-phase flow in porous media. It has two OLGA PVT options available, among which black-oil tracking is used in this project. Rocx simulations can be run without the coupling to OLGA. However, by using Rocx in combination with OLGA, more accurate predictions of well start-up and shut-down, observation of flow instabilities, cross flow between different layers, water coning and gas dynamic can be obtained (Schlumberger, 2007). The OLGA simulator is governed by conservation of mass equations for gas, liquid and liquid droplets, conservation of momentum equations for the liquid phase and the liquid droplets at the walls, and conservation of energy mixture equation with phases having the same temperature (Schlumberger, 2007).

2.1 Rocx

Schlumberger (2007) describes the mathematical models used in Rocx in detail. The models for relative permeability developed by Corey and Stone II are presented below.

In this study, the Corey model is used to define the relative permeability curves for water (Li and Horne, 2006; Rocx Online Help). This model is a combination of the Burdine approach for calculation of the relative permeability of the wetting and non-wetting phases and the capillary pressure model that was defined by Corey. The Corey model is also called the Brooks and Corey model depending on the value of the pore size distribution index. If the pore size distribution index is less than 2, the model is called the Corey model and if it is greater than 2, it is called the Brooks and Corey model (Li and Horne, 2006). The Corey model (Rocx Online Help) for predicting the relative permeability of water is given by:

$$\mathrm{k_{rw}} = \mathrm{k_{rowc}}\left(\frac{\mathrm{S_w} - \mathrm{S_{wc}}}{1 - \mathrm{S_{or}} - \mathrm{S_{wc}}}\right)^{\mathrm{n_w}} \tag{1}$$

where $\mathrm{k_{rw}}$ is the relative permeability of water, $\mathrm{k_{rowc}}$ is the relative permeability of water at the maximum water saturation, $\mathrm{S_w}$ is the water saturation, $\mathrm{S_{wc}}$ is the irreducible water saturation, $\mathrm{S_{or}}$ is the residual oil saturation and $\mathrm{n_w}$ is the Corey fitting parameter for water.

The Stone II model is used in to calculate the relative permeability of oil. This model is widely used for predicting relative permeability in water-wetted systems with high saturations of oil. The Stone II model estimates the relative permeability of oil in an oil-water system based on the following equation (Rocx Online Help):

$$k_{row} = k_{rowc}\left(\frac{S_w + S_{or} - 1}{S_{wc} + S_{or} - 1}\right)^{n_{ow}} \tag{2}$$

where k_{row} is the relative oil permeability for the water-oil system, k_{rowc} is the endpoint relative permeability for oil in water at irreducible water saturation and n_{ow} is a fitting parameter for oil.

3 Simulation Details

This section describes the simulation method and procedures. A near-well reservoir is constructed in Rocx, imported to OLGA and simulated. The results are presented using OLGA and Tecplot.

3.1 Geometry

The near-well reservoir has a length and width of 60 meter and height of 20 meters. The horizontal base pipe is located in the middle of the x-y plan and 15 meter above the bottom of the reservoir. Figure 2 presents a schematic overview of the simulated reservoir.

The water drive pressure from the bottom of the reservoir is 320 bar and the pressure in the base pipe is varied from 300 to 317 bar. Differential pressures of 3, 5, 10, 15 and 20 bars were used as the driving force for oil production in the simulation. The pressure at the outer boundary of the reservoir was constant at 320 bars, since the reservoir is considered to be infinitely large. The grid was set to (n_x, n_y, n_z) = (3, 31, 20).

3.2 Reservoir Conditions

Reservoir characteristics were chosen according to the Grane oil field in the North Sea. Grane was selected for this research since this is the first field that started to produce heavy crude oil in Norway (Fath and Pouranfard, 2014). The reservoir is characterized as homogeneous reservoir without gas-cap and with high porosity (0.33) and permeability (up to 10 D). The oil viscosity at reservoir conditions reaches 12 cP with 19°API gravity.

According to Fath and Pouranfard (2014), MMP for carbon dioxide and oil (20° API) is 320 bar (at 121 °C). The reservoir pressure in the Grane field is 176 bar. However, in order to simulate the miscible CO_2-EOR method, the reservoir pressure was set to 320 bar and the temperature to 121 °C. The rock is defined as sandstone, and the thermal properties was chosen from data given by Eppelbaum *et al* (2014). The reservoir characteristics of the Grane field and the reservoir characteristics used in this study are listed in Table 1.

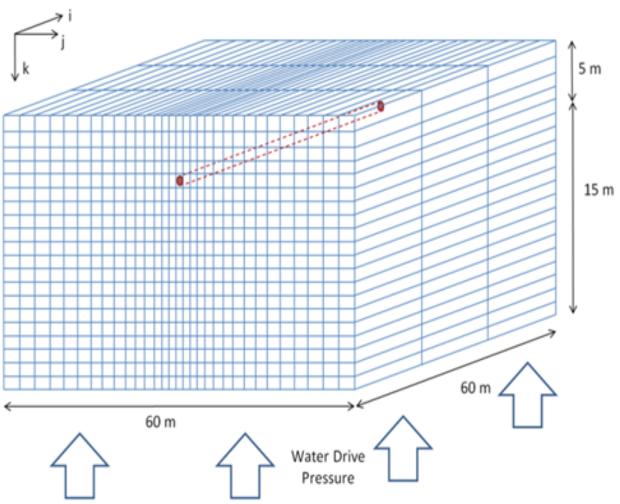

Figure 2. Schematic overview of the near-well reservoir.

Table 1. Reservoir characteristics of Grane field and the simulated reservoir.

Parameter	**Grane field reservoir**	**The simulated reservoir**
Oil viscosity	10-12 cp @ 76 °C and 176 bar	12 cp @ 76 °C and 176 bar
Oil specific gravity	0.876 (19° API)	0.876 (19° API)
Porosity	0.33	0.33
Permeability	Up to 10 D	x and y-directions: 7 D z-direction (gravity): 0.7 D
Area	25.5 km^2	1860 m^2 (60X31)
Thickness	31 m	20 m
Gas Oil Ratio	14-18 Sm^3/Sm^3	15 Sm^3/Sm^3
Reservoir pressure	176 bar	320 bar
Reservoir temperature	76 °C	121 °C
Rock compressibility	Not found	0.00001 1/bar
Rock heat conductivity	Not found	1.7 W/mK
Rock heat capacity	Not found	737 J/kgK
Rock density	Not found	2198 kg/m^3
Initial oil saturation	Not found	1
Irreducible water saturation	Not found	0.18
Residual oil saturation	Not found	0.3 (before CO_2 breakthrough)

3.3 CO_2 Injection Simulation

In OLGA, a geometry comprising of two pipelines (one injection and one production flow path), three closed nodes, one pressure node, three pressure sources and six near-well source was used to show the injection of CO_2 and enhanced oil production. This was designed using the basic case function in the OLGA model browser with a pipeline diameter of 0.12 m as shown in Figure 3.

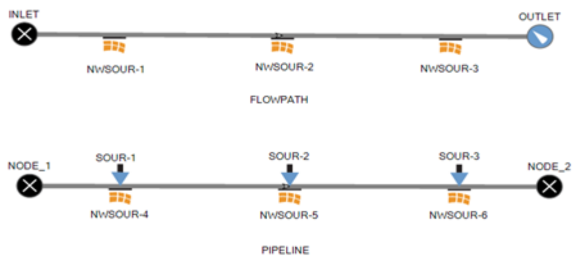

Figure 3. CO_2 injection design in OLGA.

The blackoil model was selected in Rocx and it was assumed that the reservoir was initially saturated with oil. Differential pressure was utilized as a driving force while trying to inject CO2 into the reservoir. This was implemented in OLGA with use of pressure sources and the initial injection well pressure was set to 325 bars, the pressure of the CO2 source was set to 340 bar and the reservoir pressure was set to 320 bar. This condition gave a pressure difference of 15 bar that was considered adequate for injection.

The pressure drive in the reservoir is along the vertical direction, with water coming into the reservoir from the bottom and forcing the oil towards the production well. The injection well was placed close to the bottom while the production well was placed at the upper region of the reservoir as shown in Figure 3. These precautions were taken to ensure effective injection and higher oil recovery.

The use of zones was considered able to inject CO_2 into the near well reservoir. To achieve this, zones (perforations) added along the wellbore to automatically generate inflow in all control volumes in the reservoir. The inflow was expected to be calculated between the boundary positions, as opposed to the well option, which is modeled as a point source. The reservoir pressure and temperature were assumed constant during the whole simulation period and were set to 320 bar and 121 °C respectively. The pressure in the injection well varied between 330 to 400 bar. With the differential injection pressure, it was expected that CO_2 would be injected into the Rocx near well reservoir. However, when using the black oil model, which was the only option for this project, injection of CO_2 directly to the reservoir, was not possible. The further simulations were therefore performed without the injection well, and the effect of CO_2 injection was simulated by changing the relative permeability curves.

4 Results

4.1 Optimum Differential Pressure

Simulations were performed to find the optimum differential pressure for oil production in the actual field. The differential pressure, P_{res} - P_{well}, is the driving force in the oil production, and is mentioned as drawdown. Increasing the differential pressure, increases the oil production rates, but it also increase the risk of early water or gas breakthrough. Figure 4 shows the accumulated oil production over a period of 120 days, when the drawdown was varied from 3 to 20 bar. Figure 4 shows that oil production increases with CO_2 injection. The gradient of the oil production curves indicates that the production rates are highest during the first period of production. After a certain time, the curves are becoming more flat, which shows that the oil production rates are decreasing. This occurs at different time for the different cases, and presents the time of water breakthrough. The accumulated oil production at drawdown 20 bar is about 12000 m^3 after 120 days, whereas the production using 15, 10 and 5 bar drawdown is approximately 11500, 10500 and 8200 m^3 respectively. A drawdown of only 3 bar, gives oil production of 5000 m^3 after 120 days. However, using 3 bar differential pressure, there was no additional oil production after 90 days. This indicates that the drawdown has to exceed 3 bar to get an acceptable oil recovery.

Oil recovery is greatly affected by water breakthrough. Figure 5 presents the water cut (WC) for the different drawdowns. From this figure, the optimal differential pressure that would delay water breakthrough and contribute to higher oil recovery would be determined. When using high drawdown, early water breakthrough occurs. The time of water breakthrough changes from 14 days to 84 days when the drawdown is changed from 20 bar to 3 bar. Due to the high mobility of water compared to oil, the water production increases dramatically after water breakthrough.

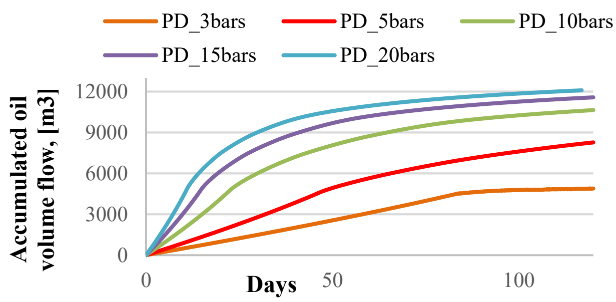

Figure 4. Accumulated oil volume flow for differential pressures of 120 days.

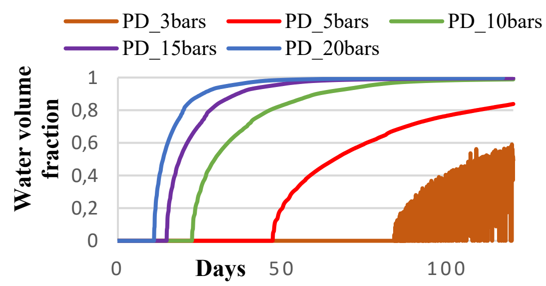

Figure 5. Water cut as a function of drawdown and time.

The Figure 5 shows that when using drawdown of 15 or 20 bars, the water cut reach a value close to unity after very short time. The cases with lower drawdown give a more moderate increase in the WC. However, it can clearly be seen that with 3 bar drawdown, big fluctuations occur. This is mainly due to numerical problems when the drawdown becomes too low. When choosing the optimum drawdown, both the breakthrough time, the water cut and the oil production rate have to be considered.

The oil production rates are presented in Figure 6. It can be seen that the production rates increase until water breakthrough occurs, and then decrease significantly. The gradient for the oil production rate is steepest for the high drawdown cases. The highest oil volume flow rates are reached at the breakthrough time, and were recorded as 360 m^3/day for 20 bar drawdown and as 40 m^3/day for 3 bar drawdown. The peaks of the oil flow rates for 15, 10 and 5 bar differential pressure were 250 m^3/day, 172 m^3/day and 78 m^3/day respectively. At 3 bar differential pressure, the flow became very unstable at the water breakthrough time, which indicates insufficient differential pressure.

Based on the simulation results with different drawdown, 10 bar was considered the optimum drawdown. The reason for choosing 10 bar drawdown, is that the increase in WC with time is much lower than for the 15 and 20 bar cases, which means that oil can be produced at lower separation costs for a longer period of time. In addition, the accumulated oil production after 120 days is only 1500 m^3 lower than for 20 bar, and the well is still producing oil at that time.

Drawdown of 5 bar gives low production rate and 3 bar drawdown gives unstable flow and no oil production after water breakthrough.

Based on this, 10 bar drawdown is used in the further simulations for studying the effect of CO_2 injection on increased oil recovery.

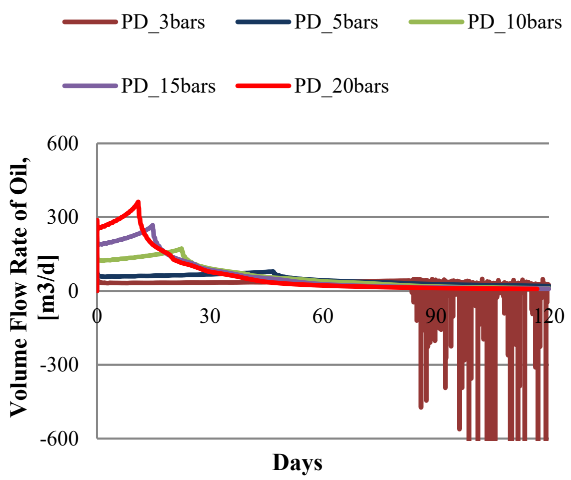

Figure 6. Volumetric flowrate of oil at differential pressures of 120 days.

4.2 CO_2-EOR

As discussed before, injection of CO_2 to the reservoir, changes the relative permeability curves. When CO_2 is injected to the reservoir, it increases the relative permeability of oil and decreases the residual oil saturation. This phenomenon was used in the simulations in order to study the effect of CO_2.

Relative permeability curves were developed in Rocx by using the Corey and STONE II models for water and oil respectively. Model fitting parameters that define the shape of the relative permeability curves were chosen assuming water-wetted rock. The fitting parameter for the water relative permeability curve can be set to 3, and for oil relative permeability curve to 2.5 (Best, 2002). Irreducible water saturation is set to 0.18. In order to simulate the effect of CO_2 injection, the residual oil saturation was decreased from 0.3 to 0.15 with a constant step of 0.05. Residual oil saturation is assumed to be 0.3 without CO_2 injection and 0.15 for effective CO_2-EOR. The relative permeability curves that were calculated are presented in Figure 7. The curves were included in Rocx and used in the further simulations to study the effect of CO_2-EOR. With CO_2 injection, oil relative permeability is increased while the residual oil saturation is reduced. This would enhance oil mobility and improve recovery.

4.3 Accumulated oil volume flow

According to the data presented in Figure 8, the accumulated oil volume flow increases with decreasing residual oil saturation. The accumulated oil production increased from about 10700 m^3 to 12000 m^3 when the residual oil saturation decreased from 0.3 to 0.15. This corresponds to an increased oil production of 12%. The differences in the accumulated oil production with varied residual oil saturation are observed after about 25 days.

This can be explained by the change in relative permeability because of CO_2 injection. At oil saturation between 0.82 and 0.75, the deviation between the relative oil saturation curves are very small, which results in insignificant differences in the oil production. The differences in oil production are getting more pronounced when the oil saturation in the reservoir decreases.

4.4 Accumulated water volume flow

As seen in Figure 9, water breakthrough to the well starts after about 24 days. The accumulated volume of water increases with increasing residual oil saturation. The water production decreased from about 90000 m^3 to 70000 m^3 when the residual oil saturation was reduced from 0.3 to 0.15. This corresponds to 22% water reduction during the 120 days of production. Hence, the higher the residual oil saturation, the higher is the total water production. This can be explained based on the relative permeability curves that are shown in Figure 7.

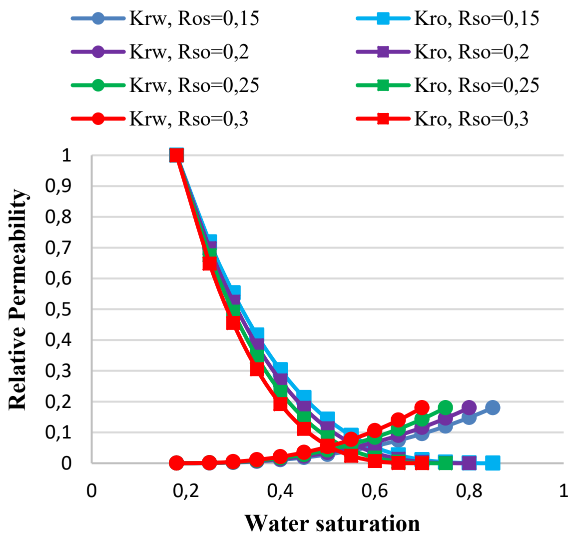

Figure 7. Tested relative permeability curves.

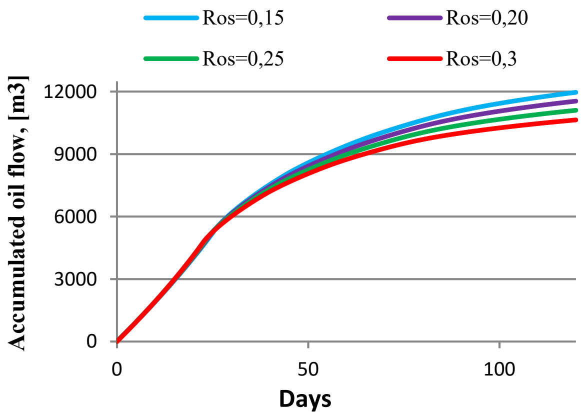

Figure 8. Accumulated oil volume flow.

When the residual oil saturation is changed the water relative permeability curve also changes. These changes are more pronounced at higher water saturations. Therefore, a decrease in residual oil saturation contributes not only to an increase in oil production, but also to a decrease in the water production.

4.5 Oil saturation in the reservoir

This study includes near well simulations, meaning that only a limited part of the reservoir is considered. Initially the reservoir contained 100% oil. After 120 days of production, the oil saturation has decreased significantly in the near well area. Figure 10 represents the reservoir saturation after 120 days when the CO_2 is injected to the reservoir and the residual saturation of oil is 0.15. The plot shows how the water from below is coning towards the well, replacing the oil. The saturation of oil varies with location in the reservoir, and the highest saturation is found above the well location.

The minimum, average and maximum oil saturation in the reservoir after 120 days are estimated and the results are presented in Figure 11. The average oil saturation in the reservoir is decreasing from 48% to 41% when the residual saturation changed from 0.3 to 0.15. The oil recovery is defined as the ratio of produced oil to the original oil in place (OOIP). In this stud, it was assumed that the initial oil saturation was 100%. The oil recovery after 120 days of production is 52%, 54%, 57% and 59% for the cases with residual oil saturation of 0.3, 0.25, 0.20 and 0.15 respectively.

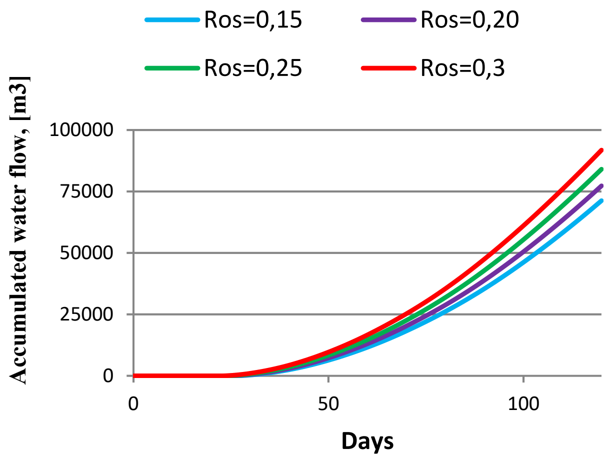

Figure 9. Accumulated water volume flow.

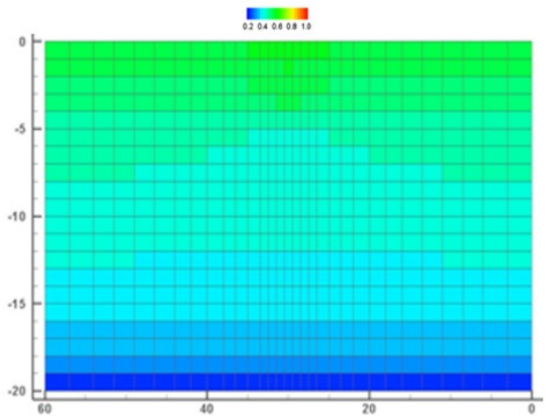

Figure 10. Reservoir YZ-profile (width-height) after 120 days of production using S_{or}=0.15.

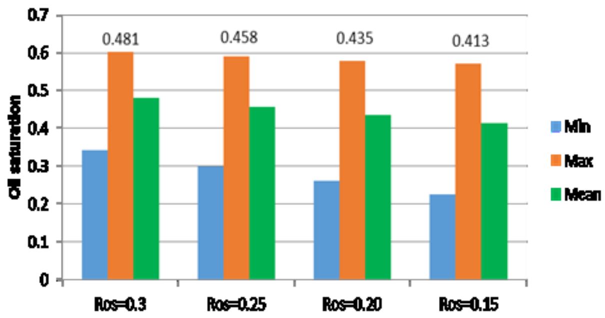

Figure 11. Oil saturation distribution in reservoir after 120 days.

5 Conclusions

Simulation of oil production is performed using the near-well software Rocx in combination with OLGA. Different models were developed to simulate CO_2 injection into the reservoir. However, the authors did not succeed in simulating CO_2 injection when the black-oil model was used, and the effect of CO_2 was studied by changing the relative permeability curves. Preliminary simulations were performed to determine the optimal drawdown for the oil production. The optimal drawdown was selected as 10 bar, because 10 bar gives stable production, relatively high oil production and acceptable water breakthrough time. A series of simulations were performed to evaluate the effect of CO_2 injection on oil recovery by adjusting the relative permeability curves using the Corey and STONE II correlations. The simulation results show that when the residual oil saturation is decreased from 0.3 to 0.15 due to CO_2 injection, the oil production increases with 12%, the water production decreases with 22%, the water cut decreases from 88% to 86% and the oil recovery factor increases from 0.52 to 0.59. This confirms that CO_2 is well suited for enhanced oil recovery.

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